Question Tracker: Questions from 5/1/2017 – Present

1

Question Topic: **OOOOa fugitives and stay**

Date Received: **5/1/2017**

Question:

I have a question for a specific scenario In regards to fugitive emission (LDAR) testing. If LDAR is required to be conducted on a wellpad by a state regulation and for example, is conducted in May 2017, then when is the next LDAR test required per Subpart OOOOa? Is it due on June 3, 2017 or would it be due in November 2017 (6 months after the last test)?

I also have a question in regards to the required online submission of the annual report via CDX. I have noticed that the only available report online for Subpart OOOOa are the performance tests. When will the annual report be available for online submission via CDX?

Response:

Response: Typically, as long as you have completed the initial monitoring requirements prior to June 3, 2017, you would not need to conduct another monitoring event before 4-6 months. The requirement is for semiannual monitoring at a well site and the rule specifies that the minimum length of time between surveys is 4 months. However, on April 18, 2017, the EPA Administrator issued a letter granting reconsideration of OOOOa's fugitive emissions standards and explained an intent to stay the June 3, 2017 compliance date for 90 days (60.5397a and associated provisions). No monitoring or reporting is required during the stay, including any CEDRI reports due during that period. While the rule itself remains in effect, and all affected facilities must be in compliance with the rule once the stay expires. EPA is aware that sources may be concerned with the uncertainty surrounding the final language of these requirements and their ability to achieve timely compliance. Our goal is to work towards ensuring that the sources have sufficient time to comply. The rest of the rule remains in effect. See: [HYPERLINK "https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-0"]

Response: Yes, we are working to get the annual report ready for online submission via CDX, and it will be available this summer.

2

Question Topic: **OOOOa initial fugitives monitoring**

Date Received: **5/9/2017**

Question:

Hi Amy,

Thank you for the clarifications today. The other question we need answered is as follow:

For a multi-well facility that is subject to NSPS OOOOa, are we required to conduct an initial fugitive emissions monitoring event (60-day) following the introduction of each new well into an affected production facility or is the requirement just twice/year once the facility is affected?

The question comes up frequently with clients. In other words, if a new facility has a new well completed into the facility each month of a calendar year, would 12 60-day initial monitoring events be required?

I appreciate any clarification you can provide on this matter.

Response:

Hi Andy,

Below is some guidance to help answer the question you sent over on Tuesday. Please let me know if you have any additional questions related to the fugitives monitoring requirements.

Section 60.5397a(f)(1) states that you "must conduct an initial monitoring survey within 60 days of the startup of production, as defined in § 60.5430a..." Therefore, the initial survey for the well site must be conducted within 60 days of the startup of production of the first well. Subsequent wells that come online after the startup of production of the first well would not subject the well site to additional 60-day initial compliance periods. However, each of the subsequent wells would be a new well site affected facility and would be subject to the applicable requirements of §60.5397a.

Thanks,
Karen

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Question Topic: **OOOOa Applicability Flare 60.18 Vmax**

Date Received: **5/10/2017**

Question:

Amy,

Thanks again for your time on the call today. This is the follow-up email that you requested after I laid out my question.

As noted during my call, as part of a proposed project to avoid having gases leak or vent to the atmosphere at an NSPS subpart OOOOa affected facility, a client would like to install a closed vent system controlled by a flare to control relief valve leakage and releases due to unforeseeable malfunctions. We're trying to confirm that the monitoring requirement in NSPS subpart VVa (40 CFR § 60.482-4a(b), by reference from 40 CFR § 60.5400a(a) in NSPS subpart OOOOa does not apply to the pressure relief devices served by this closed vent system. The planned flare is an air-assisted flare with a pressure-assist mode; the flare will operate in pressure-assist mode only during pressure release events. My regulatory analysis looks as follows:

1. The requirements in NSPS subpart OOOOa at 40 CFR §§ 60.5400a(a) and 60.5401a(b)(1) reference the requirements of NSPS subpart VVa, including 40 CFR § 60.482-4a(c), which provides the following exemption: *"Any pressure relief device that is routed to a process or fuel gas system or equipped with a* <u>*closed vent system*</u> *[emphasis added] capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482-10a is exempted. . ."*
2. Per the closed vent system and control device standards at §60.482-10a(d), *"Flares used to comply with this subpart shall comply with the requirements of § 60.18."*

As noted during our call, this is logical – if emissions from leaks will be controlled by a flare or other control device meeting the rule requirements, then there is no regulatory obligation to perform monitoring and repair to avoid those emissions. However, NSPS subpart OOOOa was developed after the *Sierra Club* decision, so it negates the generally applicable provisions regarding emissions during startup, shutdown, and malfunction events. Specifically, as 40 CFR § 60.5370a(b) states, the "provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart." Thus, per the definition of deviation at 40 CFR § 60.5430a, deviations include periods when the affected facility *"Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, . . ."*

One of the applicable requirements of 40 CFR § 60.18 is the requirement at 40 CFR § 60.18(c)(5), which mandates that each air-assisted flare "shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6)." The planned flare will operate within V_{max} during normal operation, but could exceed V_{max}during a pressure release.

Based on this analysis, I'm left with the following questions

1. Does the flare need to be designed to be compliant with the V_{max} limitation during all pressure release events, including unforeseeable malfunctions, in order to qualify for the monitoring exemption at 40 CFR § 60.482-4a(c)?
2. If I install the properly sized flare for the foreseeable operation of the flare (i.e., relief valve leakage) and I have an unforeseeable malfunction that results in a velocity at the flare tip that is greater than V_{max}, is that a reportable deviation, and, if so, in the context of which requirements?
3. If I install the properly sized flare for the foreseeable operation of the flare (i.e., relief valve leakage) and I have an unforeseeable malfunction that results in a velocity at the flare tip that is greater than V_{max}, and I report that as a deviation, is that when the language at 40 CFR § 60.5370a(b) becomes applicable?

Thank you for your consideration of these questions.

(omitted email chain from questioner seeking a follow-up from EPA staff)

Response:

Mr. May,

Thank you for patience as we worked through your question regarding how the 60.18 flare requirements apply during emergency releases from PRDs at a gas plant subject to NSPS OOOOa.

Our understanding is that the source is a gas plant and has applicability to NSPS OOOOa for the “group of all equipment within a process unit” (60.5365a(f)). Specifically of interest to you are the PRD requirements at 60.482-4a and the exemption from monitoring at 60.482-4a(c), which are cited from 60.5400a(a):

§60.482-4a Standards: Pressure relief devices in gas/vapor service.

(a) **Except during pressure releases**, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

(b)(1) **After each pressure release**, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than

500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a **control device as described in §60.482-10a** is exempted from the requirements of paragraphs (a) and (b) of this section.

[Emphasis added]

The standards at 60.482-4a apply to "leakage" (i.e., fugitive emissions) from PRD's as opposed to "releases" from PRDs. The exemption from monitoring for PRDs, which route to compliant control device (i.e. a 60.482-10a described control device, such as a 60.18 flare), therefore applies only to the fugitives monitoring requirements, not to releases from PRDs during a startup, shutdown or malfunction event.

During releases, the owner/operator of LDAR affected equipment under NSPS OOOOa would be subject to the "good air pollution control" requirements of 60.5370a(b), which may include the use of a 60.18 compliant flare. Whether a flare, which does not meet the requirements of 60.18 during a high pressure release, would be considered "good air pollution control" would have to be made on a site specific basis.

Also, other affected facilities (under NSPS OOOO/OOOOa or another NSPS) within the gas plant which generated the release (for example, a compressor or storage vessel) may have their own independent requirement to comply with the underlying emissions standard "at all times" which could include the use of a 60.18 compliant flare but would not allow the use of a flare which did not comply with 60.18. Without additional information about the emissions which route to the PRD, we are not clear as to your scenario where there is release from a PRD which doesn't come from an otherwise affected facility, but we are happy to discuss such a scenario with you, if you have an example.

For your convenience, I am also attaching Chapter 11 of the NSPS OOOOa Response to Comment Document. There is a discussion of the applicability of 60.18 during malfunctions on pdf pages 196-200 and our response on pdf page 201. There is also a discussion on the use of pressure assisted flares in the 2016 Final Rule (Attached. See 81 FR 35866 Section VI.H.5 - "Flare Design and Operation Standards"), Finally, this is not a formal determination of applicability for any specific site which you may be envisioning. We encourage you to direct the source to the appropriate delegated authority to better determine the requirements which apply based on site specifics. I am happy to help you find the appropriate contact.

Marcia B Mia
Office of Compliance/Air Branch
2227A WJCS
U.S. Environmental Protection Agency
202-564-7042

4

Question Topic: **Flares at NG Processing Plants**

Date Received: **5/10/2017**

Question:

As noted during my call, as part of a proposed project to avoid having gases leak or vent to the atmosphere at an NSPS subpart OOOOa affected facility, a client would like to install a closed vent system controlled by a flare to control relief valve leakage and releases due to unforeseeable malfunctions. We're trying to confirm that the monitoring requirement in NSPS subpart VVa (40 CFR § 60.482-4a(b), by reference from 40 CFR § 60.5400a(a) in NSPS subpart OOOOa does not apply to the pressure relief devices served by this closed vent system. The planned flare is an air-assisted flare with a pressure-assist mode; the flare will operate in pressure-assist mode only during pressure release events. My regulatory analysis looks as follows:

1. The requirements in NSPS subpart OOOOa at 40 CFR §§ 60.5400a(a) and 60.5401a(b)(1) reference the requirements of NSPS subpart VVa, including 40 CFR § 60.482-4a(c), which provides the following exemption: *"Any pressure relief device that is routed to a process or fuel gas system or equipped with a <u>closed vent system</u> [emphasis added] capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482-10a is exempted. . ."*

2. Per the closed vent system and control device standards at §60.482-10a(d), *"Flares used to comply with this subpart shall comply with the requirements of § 60.18."*

As noted during our call, this is logical – if emissions from leaks will be controlled by a flare or other control device meeting the rule requirements, then there is no regulatory obligation to perform monitoring and repair to avoid those emissions. However, NSPS subpart OOOOa was developed after the *Sierra Club* decision, so it negates the generally applicable provisions regarding emissions during startup, shutdown, and malfunction events. Specifically, as 40 CFR § 60.5370a(b) states, the "provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40

CFR 60.8(c) do not apply to this subpart." Thus, per the definition of deviation at 40 CFR § 60.5430a, deviations include periods when the affected facility *"Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, . . ."*

One of the applicable requirements of 40 CFR § 60.18 is the requirement at 40 CFR § 60.18(c)(5), which mandates that each air-assisted flare "shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6)." The planned flare will operate within V_{max} during normal operation, but could exceed V_{max}during a pressure release.

Based on this analysis, I'm left with the following questions

1. Does the flare need to be designed to be compliant with the V_{max} limitation during all pressure release events, including unforeseeable malfunctions, in order to qualify for the monitoring exemption at 40 CFR § 60.482-4a(c)?
2. If I install the properly sized flare for the foreseeable operation of the flare (i.e., relief valve leakage) and I have an unforeseeable malfunction that results in a velocity at the flare tip that is greater than V_{max}, is that a reportable deviation, and, if so, in the context of which requirements?
3. If I install the properly sized flare for the foreseeable operation of the flare (i.e., relief valve leakage) and I have an unforeseeable malfunction that results in a velocity at the flare tip that is greater than V_{max}, and I report that as a deviation, is that when the language at 40 CFR § 60.5370a(b) becomes applicable?

Thank you for your consideration of these questions.

Response:

Mr. May,

Thank you for patience as we worked through your question regarding how the 60.18 flare requirements apply during emergency releases from PRDs at a gas plant subject to NSPS OOOOa.

Our understanding is that the source is a gas plant and has applicability to NSPS OOOOa for the "group of all equipment within a process unit" (60.5365a(f)). Specifically of interest to you are the PRD requirements at 60.482-4a and the exemption from monitoring at 60.482-4a(c), which are cited from 60.5400a(a):

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(b)(1**) After each pressure release**, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482-9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a **control device as described in §60.482-10a** is exempted from the requirements of paragraphs (a) and (b) of this section.

[Emphasis added]

The standards at 60.482-4a apply to "leakage" (i.e., fugitive emissions) from PRD's as opposed to "releases" from PRDs. The exemption from monitoring for PRDs, which route to compliant control device (i.e. a 60.482-10a described control device, such as a 60.18 flare), therefore applies only to the fugitives monitoring requirements, not to releases from PRDs during a startup, shutdown or malfunction event.

During releases, the owner/operator of LDAR affected equipment under NSPS OOOOa would be subject to the "good air pollution control" requirements of 60.5370a(b), which may include the use of a 60.18 compliant flare. Whether a flare, which does not meet the requirements of 60.18 during a high pressure release, would be considered "good air pollution control" would have to be made on a site specific basis.

Also, other affected facilities (under NSPS OOOO/OOOOa or another NSPS) within the gas plant which generated the release (for example, a compressor or storage vessel) may have their own independent requirement to comply with the underlying emissions standard "at all times" which could include the use of a 60.18 compliant flare but would not allow the use of a flare which did not comply with 60.18. Without additional information about the emissions which route to the PRD, we are not clear as to your scenario where there is release from a PRD which doesn't come from an otherwise affected facility, but we are happy to discuss such a scenario with you, if you have an example.

For your convenience, I am also attaching Chapter 11 of the NSPS OOOOa Response to Comment Document. There is a discussion of the applicability of 60.18 during malfunctions on pdf pages 196-200 and our response on pdf page 201. There is also a discussion on the use of pressure assisted flares in the 2016 Final Rule (Attached. See 81 FR 35866 Section VI.H.5 - "Flare Design and Operation Standards"),

Finally, this is not a formal determination of applicability for any specific site which you may be envisioning. We encourage you to direct the source to the appropriate delegated authority to better determine the requirements which apply based on site specifics. I am happy to help you find the appropriate contact.

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Question Topic: **Storage vessels at water disposal facilities**

Date Received: **5/23/2017**

Question:

... Thank you for the info. I should have been more specific. My question relates to interpreting 60.5635(e) and 60.5635a(e). Here's a more specific question - are storage vessels at commercial injection facilities considered located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment? The NAICS for the facility I'm asking about is 213112 (Support Activities for Oil and Gas Operations).

Thank You,

Tiffanie

Response:

Tiffanie,

Sorry I missed your call yesterday. Storage vessels associated with produced water injection facilities could fall under the oil and natural gas production segment. Therefore, you would need to determine the potential emissions from the storage vessels to determine if they are considered affected facilities.

I hope this helps answer your question. Please let me know if you need any additional guidance on this.

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Question Topic: **Storage vessel once in/always in**

Date Received: **7/24/2017**

Question:

For sites that *have* an air permit requiring controls on tanks, we can look at the potential VOC emissions after controls to determine applicability to Quad O/Oa because the controls are federally enforceable. For sites that do not have an air permit requiring controls on tanks, we have to look at uncontrolled emissions to determine applicability to Quad O/Oa.

What if we have a tank that was found applicable to Quad O because we could not take into consideration the controls, but later received an air permit that made the controls federally enforceable? Can we re-evaluate applicability to Quad O/Oa, or is it once in/always in?

Response:

Thank you for your question. According to 60.5365a(e)(2), once the storage vessel is an affected facility it remains an affected facility. The language is identical in both Quad O and Quad Oa.

60.5365a(e)(2) "A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart."

7

Question Topic: **OOOOa modification of well site – sidetrack wells**

Date Received: **8/8/2017**

Question:

Can you assist with the following question or forward to someone to give a determination?

Question regarding applicability of the rules in 60.5397a for well sites.

Is a sidetrack well drilled in an existing oil/gas wellbore after September 18, 2015, considered a "new well" under 60.5365a(i)(3)?

Note: the existing well was drilled prior to September 18, 2015.

The well was never hydraulically fractured or hydraulically refractured

Sidetrack drilling to occur after September 18, 2015.

The sidetrack well would not be hydraulically fractured.

For reference: … (omitted to save space references to Sidetrack as a verb and as a noun from Schlumberger oilfield dictionary)

Response:

Based on the information provided and the regulation, a sidetrack well would be considered "drilling a new well at an existing well site". Please note that this is only guidance and if you would like to request a formal applicability determination, you would need to go through the appropriate region.

60.5365a(i)(3) states that for purposes of 60.5397a, a "modification" to a well site occurs when a new well is drilled at an existing well site. In this case, a well (a hole drilled for the purpose of producing natural gas) is being drilled at a well site (one or more surface sites that are constructed for the drilling and subsequent operation of any natural gas well).

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Question Topic: **Initial Annual Report**

Date Received: **8/8/2017**

Question:

Lisa, we spoke last week about the Quad Oa reporting requirements concerning well completions, and you directed me to the applicable regulations, include 40 CFR §§ 60.5410a and 60.5420a.

My client has three affected wells that were completed prior to Aug. 2, 2016. I understand that even if the CDX electronic reporting form has not been posted, the initial annual report for each affected well must be submitted by the applicable due date, per § 60.5420a(b)(11).

Given all the confusion with delays and stays, and the fact that the CDX form is not yet ready, what is EPA's guidance as to when these initial annual reports must be submitted?

Thanks for your assistance. – Laura

Laura L. Whiting

Partner

Response:

Hi Laura,

Following up on our conversation last week:

Wells that were completed prior to Aug 2, 2016 – initial compliance period is Aug 2, 2016 to Aug 2, 2017. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a.

Wells that were completed in Nov 2016 – initial compliance period is Nov 2016 – Nov 2017. + 90 days for your initial annual report.

Regarding CEDRI, we talked last week about 60.5420a(b)(11): (11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX ([HYPERLINK "https://cdx.epa.gov/%29"].) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site ([HYPERLINK "https://www3.epa.gov/ttn/chief/cedri/"]). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

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Question Topic: **Reporting PE Certification**

Date Received: **8/11/2017**

Question:

Name: joey hardgrave

Email Address: [HYPERLINK "mailto:jhardgrave@enercon.com"]

Comments: I am trying to identify how PE certifications for closed vent systems on storage vessels affected by NSPS OOOOa are submitted. The reg seems unclear in §60.5420a b(12) and states only that the PE certification must be "submitted." Does this go to the EPA or state administrator? Do I defer to §60.5420a b(11) and submit to EPA via CEDRI if available?

Response:

I'm following up on your question submitted through the EPA Oil and Gas Website --

The PE certification is part of the annual report, as outlined in 60.5420a(b). Your annual report must be submitted through CEDRI. If the reporting form is not available in CEDRI at the time the report is due, you must submit to the Administrator at the appropriate address listed in §60.4.

I've provided citations from 60.5420a below. Please let me know if you have further questions.

Thanks,

Lisa

Lisa Thompson

Fuels and Incineration Group

Office of Air Quality Planning and Standards U.S. Environmental Protection Agency

919-541-9775

(b) Reporting requirements. You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX ([HYPERLINK "https://cdx.epa.gov/%29"].) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site ([HYPERLINK "https://www3.epa.gov/ttn/chief/cedri/"]). If the reporting form specific to this subpart is not available in CEDRI at the time that the

report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

(12) You must submit the certification signed by the qualified professional engineer according to §60.5411a(d) for each closed vent system routing to a control device or process.

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Question Topic: **Modification of a compressor station**

Date Received: **8/21/2017**

Question:

I have a question concerning fugitive emissions survey requirements at a compressor station. Here is a brief history of the site:

2008 – Three compressor/engine sets operating per the 2008 permit modification:

- Wauk L7042GSI – EPN EXHSTKC5 – 900 hp
- Cat 3516TALE – EPN EXHSTKC6 – 1340 hp
- Cat 3606 – EPN EXHSTKC7 – 1775 hp
- Site combined hp – 4015 hp

2017 Standard Permit – added one compressor/engine set and increased total hp

- Wauk L7042GSI – EPN EXHSTKC5 – 900 hp (engine not removed but not in use since sometime prior to 2015)
- Cat 3516TALE – EPN EXHSTKC6 – 1340 hp
- Cat 3606 – EPN EXHSTKC7 – 1775 hp
- Cat 3516 – EPN EXHSTKC8 – 1340 hp
- Site combined active hp – 4455 hp

Addition of EPN EXHSTKC8 (Cat 3516) modified the site for fugitive emissions and the initial fugitive emissions survey was completed as required. The client is now planning on removing EPN EXHSTKC8 as the additional compression did not increase production as much as expected. They will not restart EPN EXHSTKC5 (Wauk) nor install any other compression. The site hp will decrease to 3115 hp. Since the site hp will be less than before the triggering event that caused the modification (installation of the Cat 3516 – EPN EXHSTKC8) will the compressor station still be required to perform quarterly fugitive emissions surveys?

Response:

Thank you for your email regarding compressor station fugitive requirements. Once the fugitive emission components have become subject to NSPS OOOOa, they remain subject, even if you later reduce the horsepower of the compressor station. The quarterly surveys will still be required.

11

Question Topic: **Definitions of semiannual and quarter**

Date Received: **9/11/2017**

Question:

Under the fugitive monitoring rules, surveys are required semiannually or quarterly. Other than stating that surveys cannot be closer than 4 months or 60 days apart, respectively. Do you know if semiannually or quarterly are defined anywhere in the rule? For example, for the semiannual surveys, are the only requirements that they must be done twice per year and no closer than 4 months? Or is there a rule or guidance document that defines semiannual as no further apart than 6 months?

Response:

As you noted, we state in the rule that semiannual monitoring must be at least 4 months apart. Similarly we state that quarterly monitoring at a compressor station must be at least 60 days apart. We don't have a specific definition of quarter or semiannual within NSPS OOOOa. However, we do adopt definitions from the General Provisions (subpart A) and NSPS VVa. In NSPS VVa we have a definition of quarter, which means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup. While we don't have a specific definition of semiannual in the regulation, we have provided guidance to others that limits the interval to a maximum of 6 months.

"Once the initial survey under §60.5397a of Subpart OOOOa is conducted, the clock starts and the next semi-annual inspection would be due within six months. Semi-annual inspections must be at least four months apart. The same would be true for a compressor station, except that subsequent surveys would be conducted every three months."

I hope this helps. Please let me know if you have any additional questions.

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Question Topic: **OOOOa – salt water disposal facilities and condensate tank farms**

Date Received: **9/12/2017**

Question:

We are working with two different clients each with an atypical O&G facility that operates upstream of custody transfer and we're interested in getting confirmation and/or clarification regarding NSPS Subpart OOOOa applicability. The issues we're encountering were not addressed in the preambles to the proposed and final rules or the background technology documents.

One is a salt water disposal facility that receives flowback from well sites and produced water from various compressor stations throughout the gathering system where additional liquids separation take place. This facility could be considered a quasi-centralized tank battery. Clearly, the salt water disposal facility is the liquid collection system for the flowback but we're also evaluating other NSPS OOOOa requirements for the storage tanks and fugitive emissions due to the incoming produced water. The incoming liquid streams contain very little VOC, conservatively estimated at one weight percent. The potential for fugitive VOC emissions is very low; however, there is no minimum VOC threshold above which monitoring is required so it appears the client will have to implement monitoring. Are we evaluating applicability correctly for this facility? Also, it appears that the only recourse is to obtain an alternative emission limit after one year of monitoring data is collected. Is this also correct?

The second facility is a condensate tank farm that receives unstabilized condensate via truck from various compressor stations throughout the gathering system. The condensate is stabilized and then trucked off-site to sales. Any produced water is either trucked to off-site sales or disposal. Recovered gas is sent to a gas plant within the system for further processing. The condensate tank farm could also be considered a quasi-centralized tank battery and appears subject to NSPS OOOOa fugitive monitoring requirements. This appears straight-forward although we'd appreciate your input on applicability for this facility as well.

Both clients have implemented the fugitive monitoring via optical gas imaging to ensure compliance with NSPS OOOOa until the applicability questions are settled. Feel free to call me on my cell phone if you'd like to discuss.

Response:

Amy Hambrick asked that I provide some feedback on your questions about fugitive emissions requirements in OOOOa. I've copied your questions here for ease of response. Please note that this information is for guidance purposes only. If the facilities would like a formal applicability determination, they should reach out to the appropriate region. I can provide a contact within the region if needed.

One is a salt water disposal facility that receives flowback from well sites and produced water from various compressor stations throughout the gathering system where additional liquids separation take place. This facility could be considered a quasi-centralized tank battery. Clearly, the salt water disposal facility is the liquid collection system for the flowback but we're also evaluating other NSPS OOOOa requirements for the storage tanks and fugitive emissions due to the incoming produced water. The incoming liquid streams contain very little VOC, conservatively estimated at one weight percent. The potential for fugitive VOC emissions is very low; however, there is no minimum VOC threshold above which monitoring is required so it appears the client will have to implement monitoring. Are we evaluating applicability correctly for this facility? Also, it appears that the only recourse is to obtain an alternative emission limit after one year of monitoring data is collected. Is this also correct?

Yes, salt water disposal wells are subject to OOOOa fugitive emissions monitoring. Well is defined at 60.5430a as "a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected." Further, the definition of a well site includes injection wells (see 60.5430a, "Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well"). You are correct that there is no minimum VOC threshold for the fugitive emissions monitoring requirements. Additionally, you could submit a request for an alternative means of emission limitation (AMEL) as you have indicated.

The second facility is a condensate tank farm that receives unstabilized condensate via truck from various compressor stations throughout the gathering system. The condensate is stabilized and then trucked off-site to sales. Any produced water is either trucked to off-site sales or disposal. Recovered gas is sent to a gas plant within the system for further processing. The condensate tank farm could also be considered a quasi-centralized tank battery and appears subject to NSPS OOOOa fugitive monitoring requirements. This appears straight-forward although we'd appreciate your input on applicability for this facility as well.

For this particular scenario, I think you should reach out to the region. The rule considers centralized tank batteries to be part of a well site, or their own separate well site for the purposes of fugitive emissions monitoring. Given that the condensate tank farm is receiving condensate from compressor stations, not wells, the region may have some additional thoughts on how the rule applies and would provide a specific determination for this facility.

Please let me know if you have any additional questions or if you need contact information for the appropriate region.

13

Question Topic: **Storage vessel applicability OOOOa**

Date Received: **9/18/2017**

Question: I had a question regarding Title 40, Chapter I, Subchapter C, Part 60 , Subpart OOOOa.

If I have a flare on location that brings my storage vessels to less than 6 tpy, am I still applicable to OOOOa?

Response:

Thank you for your question regarding applicability of OOOOa to storage vessels. Unfortunately, additional information is required to provide a specific answer to your question. Below I have outlined some guidance but if you need a formal applicability determination, you will need to contact the appropriate regional office.

60.5365a(e) says that the determination of applicability can take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local, or tribal authority. If the storage vessel is subject to requirements under an operating permit or other requirement established under a federal, state, local, or tribal authority for which the flare is used for compliance, and potential emissions are less than 6 tpy, then the storage vessel may not be an affected source under OOOOa. It is not clear from your question whether the storage vessel is subject to requirements under an operating permit or other requirement established under a federal, state, local, or tribal authority that required the use of the flare.

Please let me know if you have any additional questions.

14

Question Topic: **Annual Report Due Date**

Date Received: **9/26/2017**

Question:

Amy,

We got this from a law firm.

Deadlines under Quad Oa and Consequences for EPA (Vinson & Elkins, LLP)

When the D.C. Circuit issued its mandate, two main deadlines under Quad Oa became effective. First, Quad Oa requires that facilities covered by the rule conduct an initial monitoring survey by June 3, 2017. 40 C.F.R. § 60.5397a(f). Second, Quad Oa requires facilities covered by the rule to submit their initial annual monitoring report to EPA by 90 days after the "initial compliance period" defined under the rule ended. This compliance period ended, at the latest, on August 2, 2017, meaning that the initial annual monitoring reports are now due 90 days from that date. See 40 C.F.R. §§ 60.5420a and60.5410a. It remains to be seen whether EPA will be able to finalize its proposed rule before the reporting deadlines in Quad Oa become effective.

Conclusion (Vinson & Elkins, LLP)

The D.C. Circuit's July 31, 2017 mandate made the contested portion of Quad Oa effective as of that date. Oil and Gas operators should familiarize themselves with the current and fast-approaching deadlines of Quad Oa and should be aware that there is a distinct possibility that Quad Oa will remain in effect in the short- and medium-term. At the very least, Oil and Gas operators should be aware that Quad Oa requires covered facilities to submit an initial annual report no later than 90 days after August 2, 2017.

This means that the compliance date would be October 31st (90 days from August 2nd.) We thought it was October 1st.

Can you tell us which is correct?

Thanks,

Ian

Response:

Hi Ian,

The first annual report is due on October 31st, if your initial compliance period was Aug 2, 2016 – Aug 2, 2017.

Regarding electronic reporting, we are working on making a subpart OOOOa 60.5420a(b) Annual spreadsheet template available from the [HYPERLINK "https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri"], as well as from the Oil and Gas rule pages at the earliest by the end of the week. Currently, CEDRI is not ready to accept this report, so if by the time the compliance deadline arrives and CEDRI is not ready, you will need to submit the report to your delegated authority (State/Region). We will post updates on the CEDRI homepage if anything changes.

Please let me know if you have any further questions,

Lisa

15

Question Topic: **Stay / Is the rule in effect?**

Date Received: **9/28/2017**

Question:

Amy / Karen,

Thanks again for your guidance on the OOOOa questions a few weeks back. Wanted to check in on the status of the "stayed/not-stayed" elements of the rule.

- I recall that the 6/5/17 90-day stay was rejected by the court on 7/3/17.
- EPA subsequently moved to recall the mandate on 7/7/17 and the courts provided a 14-day period ending 7/27/17 for EPA to provide further motions.
- Since EPA did not petition the court further during that 14-day period – what does that mean for sources with OOOOa affected facilities affected by the stay?
- Is there any additional information/guidance you can provide on the 90-day stay? On the proposed 2-year stay?

Thanks!

Patty Centofanti

Trinity – Pittsburgh Office

Cell: 412-538-8038

Response:

Hi Patty -

You're correct -- on July 3, 2017, the U.S. Court of Appeals for the D.C. Circuit vacated EPA's administrative stay of portions of the 2016 New Source Performance Standards for the oil and gas industry. The court emphasized that nothing in its opinion limits EPA's authority to reconsider the oil and gas standards and to proceed with its June 16, 2017 proposed stays of certain requirements in the rule. EPA currently is reviewing the comments the agency received on the proposed stays.

EPA may elect to exercise its enforcement discretion on a case-by-case basis with respect to the fugitive emissions monitoring requirements. Companies that have specific questions regarding their compliance obligations should contact the appropriate regional office.

Thanks,

Lisa

16

Question Topic: **Reporting Storage Vessel Controls**

Date Received: **10/3/2017**

Question:

Karen-

As mentioned during our meeting this morning, I am pulling you into a question that came in. Brandon Cooper (HRP, 518-877-7101 ext112) is asking about the SV reporting requirements for enclosed combustors at 5420a(b)(6)(vii). He asks if an enclosed combustor is already approved by EPA, do they still need to submit the records listed or just state that it is already certified. From what I can tell, it appears they would be exempt from some reporting but maybe not all. What do you think?

Amy

Response:

Brandon,

Amy Hambrick forwarded me a question you sent her regarding reporting requirements for control devices. I hope the information provided is helpful. Please let me know if you need additional information.

In addition to the general site information reporting requirements, this is what is required for storage vessels in the annual report. (A facility with a non-manufacturer tested control device would be subject to reporting under §60.5420a(b)(9), and would not include the performance test in the annual report.)

Applicability	Requirement	Citation
For each storage vessel required to be in the report	Storage Vessel ID	§60.5420a(b)(1)(ii) §60.5420a(b)(6)(i)
If the storage vessel was constructed, modified or reconstructed during the reporting period	Latitude of Storage Vessel (Decimal Degrees to 5 Decimals Using the North American Datum of 1983)	§60.5420a(b)(6)(i)
If the storage vessel was constructed, modified or reconstructed during the reporting period	Longitude of Storage Vessel (Decimal Degrees to 5 Decimals Using the North American Datum of 1983)	§60.5420a(b)(6)(i)
If new affected facility or if returned to service during the reporting period	Documentation of the VOC emission rate determination according to §60.5365a(e)	§60.5420a(b)(6)(ii)
All storage vessels with deviations	Records of deviations where the storage vessel was not operated in compliance with requirements	§60.5420a(b)(6)(iii) §60.5420a(c)(5)(iii)
All storage vessel affected facilities	Statement you met the requirements specified in §60.5410a(h)(2) and (3)	§60.5420a(b)(6)(iv)

If removed from service	Date removed from service	§60.5420a(b)(6)(v)
If returned to service	Date returned to service	§60.5420a(b)(6)(vi)
For storage vessels constructed, modified, reconstructed or returned to service during reporting period that comply with §60.5395a(a)(2) with a control device tested Under § 60.5413a(d) (Manufacturer performance test)	Make of Purchased Device	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(A)
	Model of Purchased Device	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(A)
	Serial Number of Purchased Device	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(A)
	Date of Purchase	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(B)
	Copy of Purchase Order	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(C)
	Latitude of Control Device (Decimal Degrees to 5 Decimals Using the North American Datum of 1983)	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(D)
	Longitude of Control Device (Decimal Degrees to 5 Decimals Using the North American Datum of 1983)	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(D)
	Inlet Gas Flow Rate	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(E)
	Records of Pilot Flame Present at All Times of Operation	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(F)(1)
	Records of No Visible Emissions Periods	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(F)(2)

	Greater Than 1 Minute During Any 15-Minute Period	
	Records of Maintenance and Repair Log	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(F)(3)
	Records of Visible Emissions Test Following Return to Operation From Maintenance/Repair Activity	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(F)(4)
	Records of Manufacturer's Written Operating Instructions, Procedures and Maintenance Schedule	§60.5420a(b)(6)(vii) §60.5420a(c)(5)(vi)(F)(5)
For combustion control devices tested by the manufacturer in accordance with §60.5413a(d), unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/. Must be submitted via email to Oil_and_Gas_PT@EPA.GOV	Copy of the performance test results required by §60.5413a(d)	§60.5420a(b)(10)
Each closed vent system routing to a control device or process	Certification signed by a qualified professional engineer	§60.5420a(b)(12)

(unsure whether I should omit this table)

17

Question Topic: **Reciprocating Compressor Hours**

Date Received: **10/9/2017**

Question:

For NSPS OOOOa annual reporting associated with reciprocating compressor affected facilities, 5420a(b)(4) requires the reporting of hours or months since the last rod packing change. My question is which date to use of the startup date of a compressor is earlier than the Aug 2, 2016 compliance date.

For example, for a compressor with a startup on July 1, 2016 and no rod packing changes since that time, would the time be July 1, 2016 to Aug 1,

2017 OR Aug 2, 2016 to Aug 1, 2017?

Response:

Please use the date of the startup of the compressor. In your example, counting the hours from July 1, 2016 is correct. I've included the relevant regulatory text below. Please let me know if you have any further questions.

40 CFR 60.5385a(a)

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

18

Question Topic: **CTG – Storage Vessels routing to a process**

Date Received: **10/16/2017**

Question:

From: stephen.sloan42@gmail.com [mailto:stephen.sloan42@gmail.com]

Sent: Monday, October 16, 2017 1:34 PM

To: Marsh, Karen <Marsh.Karen@epa.gov>

Subject: Re: Storage Vessels

In case I phrased that poorly, there are likely many beneficial uses for the gas. Are the only 2 options allowed VRUs and combustion or can you just show that it is being utilized?

Sent from my iPad

> On Oct 13, 2017, at 5:49 AM, Marsh, Karen <Marsh.Karen@epa.gov> wrote:

>

> Mr. Sloan,

>

> Thank you for your question regarding storage vessels. Before I can provide a response, can you provide some additional information as to the context of the question. Is there a specific requirement that you are referring to?

>

> Thanks,

> Karen

>

> **

> Karen R. Marsh, PE

> US EPA, OAQPS, Sectors Policies and Programs Division Fuels and

> Incineration Group

> 109 TW Alexander Drive, Mail Code E143-05 Research Triangle Park, NC

> 27711

> Direct: (919) 541-1065; email: marsh.karen@epa.gov

>

> -----Original Message-----

> From: Thompson, Lisa

> Sent: Wednesday, October 11, 2017 8:30 AM

> To: stephen.sloan42@gmail.com

> Cc: Marsh, Karen <Marsh.Karen@epa.gov>; Hambrick, Amy

> <Hambrick.Amy@epa.gov>

> Subject: RE: Storage Vessels

>

> Hi Stephen --

>

> I'm referring your question to Karen Marsh in my office (copied here), who will get back to you shortly.

>

> Thanks,

> Lisa

>

> -----Original Message-----

> From: stephen.sloan42@gmail.com [mailto:stephen.sloan42@gmail.com]

> Sent: Tuesday, October 10, 2017 9:09 PM

> To: Thompson, Lisa <Thompson.Lisa@epa.gov>

> Subject: Storage Vessels

>

> With regards to storage vessels, does the gas need to be combusted/vaporized or can the gas be utilized other ways (as long as it's beneficial reuse)?

>

> Sent from my iPad

Response:

Hi Stephen,

We understand your question refers to how a given state will apply the CTG in a RACT determination. The recommended RACT level of control for storage vessels is 95%. As you note, section 4.3.1.1 of the CTG (Routing Emissions to a Process via a Vapor Recovery Unit) and section 4.3.1.2 (Routing Emissions to a Combustion Device) are described as options for controlling storage vessel emissions to the RACT level. It is up to the state to implement RACT; they may use the guidance in the CTG or may implement other technically sound approaches.

The EPA will evaluate the RACT determinations and determine, through notice and comment rulemaking, whether these determinations in the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. Absent such a submitted rule, it is premature to determine whether a particular scenario you are envisioning would meet the specific state's determination of RACT.

To the extent an air agency adopts any of the recommendations in this guidance into its RACT rules, you can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of these rules and the EPA's SIP process. We encourage you to work with your state to remain engaged in this process.

If you wish some guidance on the requirements in the NSPS OOOO or OOOOa, we are happy to walk you through those standards, as they relate to the control of storage vessel emissions (specifically the option to "route to a process").

Thanks,
Karen

19

Question Topic: **Stays in Effect**

Date Received: **10/16/2017**

Question:

What is the current status of the fugitive emissions Leak Detection and Repair (LDAR) for reciprocating compressor and well affected facilities? Are subject producers required to complete the testing, or is the stay (additional 30-day, then 2-year) still in effect?

Please advise,

Thank you

Response:

On July 3, 2017, the U.S. Court of Appeals for the D.C. Circuit vacated EPA's administrative stay of portions of the 2016 New Source Performance Standards for the oil and gas industry. The court emphasized that nothing in its opinion limits EPA's authority to reconsider the oil and gas standards and to proceed with its June 16, 2017 proposed stays of certain requirements in the rule. EPA currently is reviewing the comments the agency received on the proposed stays.

EPA may elect to exercise its enforcement discretion on a case-by-case basis with respect to the fugitive emissions monitoring requirements. Companies that have specific questions regarding their compliance obligations should contact the appropriate regional office.

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Question Topic: **Certifying Official for Limited Liability Companies**

Date Received: **10/18/2017**

Question:

Lisa:

Thank you very much for speaking with me this morning. Please let me know your thoughts on how the Agency interprets "certifying official," as defined in 40 C.F.R. 60.5430 and 5430a, when the owner or operator of an affected facility is a limited liability company.

I really appreciate your help.

Thanks,

Gary

Response:

Hi Gary,

We had Padma look into this, and the 4th option for certifying officials would apply to a limited liability company.

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

I've also included preamble text from the 2014 OOOO proposed amendments (when the CO term was introduced) as background. Please let me know if you have any further questions.

Thanks,

Lisa

The 2012 final rule requires certification by a responsible official of the truth, accuracy and completeness of the annual report. Petitioners pointed out that the definition of "responsible official" is not appropriate for the oil and natural gas sector due to the large number and wide geographic distribution of the small sources involved. Petitioners suggested that the EPA should develop a certification requirement specific to the Oil and Natural Gas Sector NSPS that would allow delegation of the authority of a responsible official to someone, such as a field or production supervisor, who has direct knowledge of the day to day operation of the facilities being certified, without requiring that such delegation be pre-approved by the permitting authority.12

We reexamined the definition of "responsible official" and agree with petitioners that the current language in the NSPS, specifically the requirement to seek advance approval by the permitting authority of the delegation of authority to a representative if the facility employs 250 or fewer persons, is too burdensome for the oil and natural gas sector. The oil and natural gas sector, especially the production (i.e., "upstream") segment, is characterized by many individually small facilities (e.g., well sites) with oversight typically by a production field office serving a large geographic area such as a basin. We believe a production supervisor or field supervisor who is in charge of a field office would be analogous to a "plant manager" in other sectors, because he or she is "responsible for the overall operation of one or more manufacturing, production, or operating facilities" (from § 60.5430, definition of "responsible official"). We believe positions such as these are much closer to the day to day operations in this sector and would be appropriate to certify as to the truth, accuracy and completeness of annual reports and compliance certifications. However, because most oil and gas production facilities are small and therefore unlikely to have more than **250** persons, delegating the authority of responsible official to an oil and gas production supervisor or field supervisor would almost always require the permitting authority's approval.

We believe that the oil and natural gas sector is unique in that the ones with most knowledge of the facilities being certified are field or production supervisors overseeing such facilities, which are numerous across country but generally with few employees in each facility. As a result, requiring prior approval of a delegation of the authority of a responsible official because most of these facilities employ **250** persons or less is unnecessarily burdensome and may potentially affect the facilities' ability to comply with the certification requirement in the event there are delays in approvals of delegation. We therefore propose requiring advance notification instead of advance approval before such delegation becomes effective.

Petitioners also noted that the current definition does not adequately address the complex ownership arrangements of limited partnerships. We agree with the petitioners and believe limited partnerships should be reflected in the definition along with sole proprietorships and partnerships which are currently addressed.

In light of the considerations discussed above, we are proposing to amend the definition of "responsible official" to make such delegation effective after advance notification rather than after approval. Requirements for delegation to representatives responsible for one or more facilities that employ more than **250** persons or have gross annual sales or expenditures exceeding $25 million (in second quarter **1980** dollars) are unchanged from the 2012 NSPS (i.e., there is no advance notification or approval required for such delegations).

In addition, the 2012 NSPS uses the term "permitting authority" in the definition of "responsible official." The NSPS is not a permitting program, and the annual compliance certification that requires signature of the "responsible official" is a requirement of the NSPS and is not associated with a permitting program. As a result, we are proposing to replace the term "permitting authority" with "Administrator" in the definition of "responsible official" to be consistent with other notification and reporting requirements of the NSPS.

21

Question Topic: **Fugitive Emissions – storage vessels**

Date Received: **10/18/2017**

Question:

I am a consultant to the Oil and Gas Industry. I previously manged the Environmental Department at Devon Energy. Some of my new clients are using the definition (40CFR60.5430a Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.) of fugitive emissions to say that if a storage vessel is NOT controlled then the thief hatches and Enardo valves are allowed to leak. This does not seem to line up with spirit of the rule. Please advise.

Response:

As you mentioned in your question, the definition of "fugitive emissions component" excludes certain equipment. Specifically, the definition of fugitive emissions component means "any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open ended lines, flanges, covers and closed vent systems not subject to 60.5411a, **thief hatches or other openings on a controlled storage vessel not subject to 60.5395a**, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. **Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions**."

The bolded text describes fugitive emissions from controlled storage vessels. The thief hatches or Enardo valves on an uncontrolled storage vessel are not considered fugitive emissions because these devices vent as part of normal operation. If a storage vessel has uncontrolled emissions below 6 tpy, then there are no control requirements, including fugitives. If, however, the storage vessel utilizes controls for any reason outside of compliance with the requirements in 60.5395a, then the emissions from a thief hatch or Enardo valve would be subject to fugitive emissions monitoring.

I hope this helps. Please let me know if you have any additional questions.

22

Question Topic: **CEDRI Template Form**

Date Received: **10/20/2017**

Question:

Lisa,

Thanks for the Template, I have a couple of questions if you don't mind.

1. The only fields that seem to migrate through the workbook is the Facility Record No. Was that intentional, even though there are fields that should be the same on all tabs, i.e. US Well ID, Latitude, Longitude and possibly Associated file name. In our program, once the operator puts the information in for the Site, when they travel to other Tabs the information is there. We were thinking this would narrow the possibility of mistakes being made between tabs.

2. Isn't it necessary for the Location to be on each tab, and is there a reason the location in "Well Tab" is one column instead of a separate Latitude and Longitude, especially when trying to transmit when CEDRI is up and running.

Thanks Again for the Template and I'm not trying to cause issues or problems. Have a Nice Weekend and GO LSU

Response:

Hi Keith –

Thanks for this information – it's always helpful to get this type of feedback so we can work to improve the template in the future.

1 – We're planning to look into linking US Well ID throughout the template, but not lat / long – this should differ based on each piece of equipment being reported.

2 – We don't think it's necessary for location to be on each tab because the Facility Record No located on each tab will provide a crosswalk to the location, and we would prefer to consolidate all this on the site information tab where the rule allows for it. For the well location, the rule requires reporting of "The location of the well" (see 60.5420a(c)(1)(iii)(A)). This could be lat/long, which we used as an example, but someone could also report an address – so we've include just one cell for this entry.

Thanks again for the feedback.

23

Question Topic: **Offshore applicability**

Date Received: **10/27/2017**

Question:

Name: Chris Lindsey

Email Address: [HYPERLINK "mailto:clindsey@slrconsulting.com"]

Comments:

We have a technical question about applicability of Subpart OOOOa to offshore facilities. We understand that EPA has provided a response to comments on the rule regarding offshore platforms not being applicable. But, we are requesting guidance on applicability for man-made islands. Thank you.

Chris Lindsey

907-264-6916

Response:

Hi Chris,

OOOOa only applies to onshore facilities in the Oil and Natural Gas Source Category. Onshore is defined as "all facilities except those that are located in the territorial seas or on the outer continental shelf". If you have questions about if your facility is located in the territorial seas or outer continental shelf, please contact the appropriate delegated authority. I am happy to help you find the appropriate contact.

Thanks,

Lisa

24

Question Topic: **Modification of a storage vessel**

Date Received: **11/6/2017**

Question:

What constitutes modification , under OOOOa, to a storage affected facility?

If a storage facility is determined to not be subject to controls under OOOO because it is less than 6 TPY/tank and new wells are drilled and tied into the facility, does the 6 TPY/tanks need to be redetermined ?

Response:

I wanted to get back with you regarding your questions on modification of a storage vessel under NSPS OOOOa. In your question, you asked what constitutes a modification to a storage vessel and provided an example. First, we in the absence of a definition within subpart OOOOa, we use the definition of modification found in the General Provisions of Part 60. That definition states that modification "means any physical change in, or change in the method of operation, of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emissions of any air pollutant (to which a standard applies) into the atmosphere not previously emitted." The key points here relate to the increase in emissions.

Section 60.5395a(a)(3)(ii) in OOOOa requires calculation of potential emissions from the storage vessel after a well is fractured or refractured and sends fluids to the storage vessel. If you determine that there is an increase in emissions from what you calculated previously for this storage vessel, then a modification would have occurred.

I hope this helps to answer your question. Please let me know if you have any additional questions.

25

Question Topic: **OOOOa – Fugitive monitoring schedule**

Date Received: **11/9/2017**

Question:

Hello,

§60.5397a (g)(1) states: A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart.

If I have an initial survey conducted on July 15, 2017, that means my first semi annual test must occur between November 16, 2017 and January 15, 2018 correct?

There are some within my company that would like to treat the definition of semi annual as “twice a year” and not “every six months”.
Using this definition the July 15, 2017 survey would be in the second half of the year and the next survey must be conducted between January 1 and June 30, 2018. Since January is greater than 4 months from the initial inspection and is the first month in 2018.

Can you please help settle the debate?

Response:

Hi Zachary,

Thanks for your question on the timing of the semiannual monitoring after an initial inspection. Based on the information you provided, the first semiannual monitoring should occur by January 15, 2018. You are correct that the shortest time between semiannual monitoring is 4 months (or as early as November 16, 2017 in your specific case). From that point, monitoring must occur no closer together than 4 months and must occur within 6 months of the previous monitoring event. These semiannual monitoring events are not tied to the calendar year.

Please let me know if you have any additional questions.

26

Question Topic: **Non-compliance**

Date Received: **11/12/2017**

Question:

Comments: Would a company not complying with the requirements for fugitive emissions be violating the Clean Air Act or another law?

Response:

Thank you for your question below:

Comments: Would a company not complying with the requirements for fugitive emissions be violating the Clean Air Act or another law?

Response: A company subject to standards (in your example, fugitive emissions standards for oil and gas production) and for which they do not comply may be found in violation of those requirements.

Please visit our "Small Entity Compliance Guide" at [HYPERLINK "https://www.epa.gov/sites/production/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf"], specifically the following sections, for more information:

13.3 What is the compliance assurance process?

13.4 If the Agency discovers a violation, what might be its response?

13.6 How do I minimize harm if I think I am out of compliance?

Marcia B Mia

Office of Compliance/Air Branch

2227A WJCS

U.S. Environmental Protection Agency

202-564-7042

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Question Topic: **OOOOa- Capital Expenditure**

Date Received: **11/15/2017**

Question:

What should facilities do when calculating the capital expenditure since the 2011 date does not work in the definition within the final rule?

Response:

Jamie,

I wanted to follow up with you from our call yesterday. I was also unable to find any specific guidance we have related to the use of the Capital Expenditure equation for natural gas processing plants. We do know about the issue with the 2011 date. In the meantime, since this would affect applicability, my recommendation is that you reach out to the appropriate region for their guidance on this. A list of regional contacts can be found in the Small Entity Compliance Guide located at the link below. Let me know if there's anything else I can assist with in the future.

[HYPERLINK "https://www.epa.gov/sites/production/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf"]

Thanks,
Karen

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Question Topic: **Status of Stay**

Date Received: **12/6/2017**

Question:

Can you please clarify for me the status of the 2 year stay on the NSPS Subpart OOOOa in light of the information data that was released November 1?

Are all requirements of Subpart OOOOa active now? And should any facilities that are applicable to the requirements be following them now?

Thank you

Teresa Dunin

Response:

The 2-year stay was proposed on June 16, 2017. The notices from November are Notices of Data Availability related to the Agency's proposed stays. The notices seek comment on some of the issues and suggestions stakeholders have identified since the agency proposed a two-year stay and a three-month stay of certain requirements in the 2016 rule. The comment period for the NODAs closes on 12/8/2017. The EPA is in the process of reviewing comments we received on the proposed stays and on the NODAs, and the stays have not yet been finalized.

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Question Topic: **OOOOa – Fugitive monitoring schedule**

Date Received: **12/12/2017**

Question:

Karen-

I know I will get this question from my clients, so I'll go ahead and ask now. Based on your explanation below, which I do follow, it is possible to have a scenario where three surveys would be required in one calendar year for a wellsite facility.

Example:
Survey date 1/15/18 (next survey due 5/15-7/15/18)
Survey Date 6/30/17 (next survey due 10/30/17-12/30/17)
Survey date 12/30/17

Is this correct?

Also, I wanted to pick your brain on how surveys should be handled specifically to storage tanks at facilities subject OOOOa. The rule is specific in that for tanks that are controlled, any gas detected from the thief hatch is a leak. This implies, that for tanks that are uncontrolled, that gas from the hatch would NOT be a leak.

For tanks that are not controlled, should they even be surveyed at all, i.e. identified within the observation path? If the tank is authorized to vent to atmosphere, would any component on the tank have the potential for a leak? Again, this seems like it would be black and white, but there are so many "what-if" questions that are being raised.

Thanks!
Jamie

Response:

Jamie,

Based on the example you have provided, it could be possible for 3 surveys to take place within a calendar year. Since monitoring can occur as soon as 4 months, but no more than 6 months after the previous monitoring survey, it is possible for this scenario to occur.

Tanks that are not subject to control (for any reason) are not required to be monitored. However, there may be fugitive emissions components (e.g., valves at the inlet/outlet of the tank) that would be monitored, so it may be necessary to include the tank in the observation path to ensure these components are monitored. Any venting to the atmosphere from the thief hatch would not be considered a fugitive emission for uncontrolled storage tanks.

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Question Topic: **OOOOa – Fugitive monitoring with drone**

Date Received: **12/14/2017**

Question:

Hi Lisa – it was nice chatting with you earlier today.

As I explained, CEC is exploring the use of drone technology to perform OGI surveys at well sites for compliance with the NSPS OOOOa fugitive emission component LDAR requirements (40 CFR 60.5397a).

Assuming that the applicable requirements of the rule are met, does U.S. EPA have any prohibition or limitation about using drone-mounted OGI cameras for these surveys?

Thanks very much,

Kris

Response:

Kris,

Lisa Thompson forwarded me your email regarding the use of drones for OOOOa fugitive emissions monitoring. The language in 60.5397a was written with drone-mounted OGI in mind. One key aspect is ensuring you have a line of sight on all regulated components, which is why the observation path is an important aspect of the monitoring plan. Provided the requirements of 60.5397a are met, this is a valid method for fugitive monitoring.

Please let me know if you have any other questions.
Thanks,
Karen

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Question Topic: **OOOOa applicability – Distribution / Local Distribution Company Custody Transfer Station**

Date Received: **12/27/2017**

Question:

From: [HYPERLINK "mailto:Kevin.Fortune@epa.ohio.gov"] [[HYPERLINK "mailto:Kevin.Fortune@epa.ohio.gov"]]
Sent: Wednesday, December 27, 2017 4:51 PM
To: Thompson, Lisa <[HYPERLINK "mailto:Thompson.Lisa@epa.gov"]>; Hambrick, Amy <[HYPERLINK "mailto:Hambrick.Amy@epa.gov"]>
Subject: FW: EOG - Chippewa Station Air Permit Questions

Lisa and Amy,

I deal with OOOO/OOOOa quite a bit and but was obviously unsure with this scenario, please see the emails below and let me know if what Liz is telling me is correct and they wouldn't be subject to OOOOa. If you need more clarity or the application section she is referring to let me know.

Thanks,

Kevin

From: Elizabeth H Gayne [[HYPERLINK "mailto:Elizabeth.H.Gayne@dominionenergy.com"]]
Sent: Wednesday, December 27, 2017 11:59 AM
To: Fortune, Kevin <[HYPERLINK "mailto:Kevin.Fortune@epa.ohio.gov"]>
Cc: Abby M Credicott <[HYPERLINK "mailto:abby.m.credicott@dominionenergy.com"]>; Thomas R Andrake <[HYPERLINK "mailto:Thomas.R.Andrake@dominionenergy.com"]>
Subject: RE: EOG - Chippewa Station Air Permit Questions

Hi Kevin –

I wanted to follow up with you after leaving you a voicemail. In the permit application submitted for Chippewa Station on 12/20, applicability of NSPS OOOOa is reviewed in section 3.1.3.3 (pg. 3-3). Chippewa Station is located downstream of the local distribution company point of custody transfer station and is used exclusively for distribution of Natural Gas to customers of EOG. NSPS OOOOa regulates natural gas production facilities, wells, and transmission facilities, however does not extend into the distribution sector. Because of this, Chippewa Station is not an affected facility as defined by OOOOa.

Please feel free to call me if you have any questions.

Liz

Elizabeth Gayne

Manager, Environmental - Dominion Energy Corporate Air Programs

5000 Dominion Boulevard, Glen Allen, Virginia 23060

804-273-3128 (office) 804-201-3418 (cell)

[HYPERLINK "mailto:Elizabeth.H.Gayne@dominionenergy.com"]

From: [HYPERLINK "mailto:Kevin.Fortune@epa.ohio.gov"] [[HYPERLINK "mailto:Kevin.Fortune@epa.ohio.gov"]]
Sent: Wednesday, December 27, 2017 10:44 AM
To: Thomas R Andrake (Services - 6)
Cc: Abby M Credicott (Services - 6); Elizabeth H Gayne (Services - 6)
Subject: [External] EOG - Chippewa Station Air Permit Questions

T.R., Abby and Liz,

I am reviewing the application and noticed the fugitive emissions/leaks source (P019) has essentially seen emissions increases with each modification to the facility. I believe 40 CFR Part 60, Subpart OOOOa is now subject due to 60.5365a(j)(1) & (2). This will require this source to have periodic LDAR and be included in the PTI.

Also, it appears the two new engines/compressors will have to comply with 60.5385a, which is the rod packing requirements. Making sure Dominion agrees with these requirements since it wasn't included in the application.

I think I missed this with emissions unit B015 (Engine #8), we will have to modify that permit to include OOOOa.

Let me know if you have any questions and if you agree.

Thanks,

Kevin Fortune

Environmental Specialist 2

Division of Air Pollution Control

Ohio Environmental Protection Agency

(330) 963-1152

Response:

Hi Kevin,

If this facility is located in the distribution segment, or past the 'local distribution company custody transfer station' as Liz claims, then OOOOa does not apply. OOOOa applies from the wellhead up to the 'local distribution company custody transfer station'.

OOOOa defines this as:

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines. (60.5430a)

Let me know if you need anything else!

Lisa

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Question Topic: **Testing requirements for flares controlling storage vessels; OOOOa**

Date Received: **1/10/2018**

Question:

To: 'Hambrick.Amy@epa.gov' <Hambrick.Amy@epa.gov>
Subject: NSPS OOOO/OOOOa question concerning Flares

Amy,
I was hoping you could help me in an interpretation of "combustion device" vs "flare" under NSPS OOOO and OOOOa. It appears the wording in these subparts distinguishes between combustion device and flare and are listed separately. Am I correct it interpreting that a flare (open candle stick type unit) is not considered a combustion device in the rule? The rule defines "completion combustion device" and "flare", which specifically says it is not a completion combustion device, but does not define

"combustion device". Specifically, I am trying to determine if the monthly 15 minute Method 22 readings are required for flares controlling storage tanks. It appears that they are not since they are not defined as combustion devices in the rule. Rather, flares are subject to 60.18 and if visible emissions are observed a 2 hour Method 22 reading would be required to ensure no more than 5 minutes in any 2 hours for compliance with "smokeless" conditions. See excerpts below from OOOO supporting this interpretation. I have highlighted the sections I believe are applicable to flares and the associated cover/closed vent system.

Response:

From: Witosky, Matthew
Sent: Thursday, January 11, 2018 8:34 AM
To: 'ashley.campsie@eeeng.net' <ashley.campsie@eeeng.net>
Cc: Thompson, Lisa <Thompson.Lisa@epa.gov>; Garwood, Gerri <Garwood.Gerri@epa.gov>
Subject: NSPS OOOO/OOOOa question concerning Flares

Hi Ms. Campsie,

Thank you for your question. A flare is not considered an enclosed combustion device, but is considered a combustion control device.

You wrote "Specifically, I am trying to determine if the monthly 15 minute Method 22 readings are required for flares controlling storage tanks. "

Yes, flares that are control devices for storage vessels are combustion devices, and are required to comply with 60.5412a(d)(1) (ii) and (iii) as well as 60.5412a(d)(3) and (4).

This also means that flares controlling storage vessels are subject to continuous compliance requirements in 60.5417(h)(1)and (3). 60.5417a(h)(4) does not apply.

Let us know if you have additional questions. Have a great day.

Sincerely,

Matthew Witosky

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Question Topic: **CEDRI due date**

Date Received: **1/29/2018**

Question:

Lisa:

In late October 2017 we sent TCEQ Subpart OOOOa reports for two clients for the time period August 2, 2016- August 2,

Now that the Subpart OOOOa template is in CEDRI, what is the deadline for submitting these repots in CEDRI that were sent to the Agencies in October 2017?

Response:

Hi Roger,

We've posted a draft template for the OOOOa Annual Report in CEDRI. You may use this to submit your next annual report, but reporting in CEDRI is not required until 90 days after the final template is available. We will update our website once the final CEDRI template is available. [HYPERLINK "https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry"]

Please also note that you do not need to resubmit any annual reports through CEDRI that have previously been submitted to your delegated authority.

Please let me know if you have any further questions.

Lisa

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Question Topic: **CEDRI annual report due date**

Date Received: **1/29/2018**

Question:

Ms. Thompson,

Since the reporting template for OOOOa did not come out 90 days prior to the October 31, 2017 deadline, we filed our clients' OOOOa reports by hard copy to the appropriate EPA or state office. A client told me that someone told them that the OOOOa reports filed in October, 2017 now have to be re-filed through CEDRI by February 9, 2018. Is this true? My understanding is that we have to begin using the system for the October, 2018 filing.

Response:

Hi Deborah,

You're correct – the OOOOa annual report template in CEDRI is not final, and therefore the 90 day clock has not started. You do not need to re-file in CEDRI for this year's annual report, and we will update our website once the final CEDRI template is available.

[HYPERLINK "https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry"]

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Question Topic: **Semiannual monitoring definition**

Date Received: **2/14/2018**

Question:

Hello Brenda,

I hope this message reaches you well.

I left a voice message and wanted to follow up via email. I was referred to you by colleagues as someone I could connect with on US EPA rule OOOOa.

I wanted to know if the OOOOa definition of semiannual (surveys) can be interpreted as "twice a year". I am looking to seek alignment and confirmation as I was not able to find an US EPA definition of semiannual within the rule. If there is someone else I should be speaking to please let me know.

Response:

Byron,

Thanks for your question on the timing of the semiannual monitoring after an initial inspection. Following initial monitoring, semiannual monitoring must occur no closer together than 4 months and must occur within 6 months of the previous monitoring event. These semiannual monitoring events are not tied to the calendar year. It is possible that 3 semiannual events could take place in a calendar year depending on when the monitoring events take place.

Please let me know if you have any additional questions.

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Question Topic: **Compressor applicability, fugitives modification for compressors**

Date Received: **2/23/2018**

Question:

1. **<u>Servicing more than one well</u>** - §60.5365a(c) states that "*Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.*"

Does this mean that a reciprocating compressor that services more than one well site is not an affected facility whether it is located on a well site or not? We are seeing different interpretations for this regulatory citation across the Coalbed Methane industry.

Installation Date - In determining applicability between NSPS Subpart OOOO and NSPS Subpart OOOOa, is the applicability date determined by the actual reciprocating compressor installation date or the engine installation date?

1. For example, if a reciprocating compressor and the engine that powers the reciprocating compressor were installed in 2012, (subject to NSPS, Subpart OOOO), and the engine that powers the reciprocating compressor was replaced in 2016, would the compressor remain subject to NSPS Subpart OOOO or are they now subject to NSPS Subpart OOOOa?

   <u>Increase in horsepower</u> - In determining the applicability to the collection of fugitive emission components at a compressor station for the purpose of §60.5397a, it states that a modification to a compressor station occurs when *"(2) One or more compressors at a compressor station is replaced by one or more compressors of a greater total horsepower that the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) does not trigger a modification of the compressor station for the purpose of §60.5397a."*

Does this refer to the engine that powers the compressor or the compressor only, since Subpart OOOOa never mentions engines? Compressors are typically rated for a max horsepower matched to a similar sized engine. If the compressor is rated at 1000 hp and the engine is 500 hp and they replace the engine with a 600 hp without changing the compressor, does that trigger a modification as defined by §60.5365a(j)?

Response:

1. **<u>Servicing more than one well</u>** - §60.5365a(c) states that "*Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.*"

Does this mean that a reciprocating compressor that services more than one well site is not an affected facility whether it is located on a well site or not? We are seeing different interpretations for this regulatory citation across the Coalbed Methane industry.

A reciprocating compressor that services more than one well site is not an affected facility, if it is located at a well site. If it is not located at a well site, it would be an affected facility.

2. **Installation Date** - In determining applicability between NSPS Subpart OOOO and NSPS Subpart OOOOa, is the applicability date determined by the actual reciprocating compressor installation date or the engine installation date?

For example, if a reciprocating compressor and the engine that powers the reciprocating compressor were installed in 2012, (subject to NSPS, Subpart OOOO), and the engine that powers the reciprocating compressor was replaced in 2016, would the compressor remain subject to NSPS Subpart OOOO or are they now subject to NSPS Subpart OOOOa?

For purposes of the standards for reciprocating compressors in subparts OOOO and OOOOa, the affected facility is the compressor, not the engine. See 40 CFR 60.5365(c) and 60.5365a(c). The engine could come into play if the replacement of the engine resulted in an emissions increase to the atmosphere from the compressor such that it was determined a modification occurred pursuant to §60.14. Additionally, the EPA intends that the "commence construction" date for a reciprocating compressor affected facility to be the date an owner or operator has entered into a contractual obligation to acquire the compressor, not the installation date. We clarified this in the August 16, 2012, final NSPS OOOO rule (see 79 FR 59423). Therefore, the date the owner or operator entered into a contractual obligation to purchase the compressor determines applicability to the NSPS.

3. **Increase in horsepower** - In determining the applicability to the collection of fugitive emission components at a compressor station for the purpose of §60.5397a, it states that a modification to a compressor station occurs when *"(2) One or more compressors at a compressor station is replaced by one or more compressors of a greater total horsepower that the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total*

horsepower than the compressor(s) does not trigger a modification of the compressor station for the purpose of §60.5397a."

Does this refer to the engine that powers the compressor or the compressor only, since Subpart OOOOa never mentions engines? Compressors are typically rated for a max horsepower matched to a similar sized engine. If the compressor is rated at 1000 hp and the engine is 500 hp and they replace the engine with a 600 hp without changing the compressor, does that trigger a modification as defined by §60.5365a(j)?

You asked two questions:

Q1:Does this refer to the engine that powers the compressor or the compressor only, since Subpart OOOOa never mentions engines?

A1: You are correct that the engine is related to the HP of the compressor. However, the rule applies to the HP of the compressors at the compressor station. We evaluate HP increase of the compressor station as a modification, regardless of whether the compressors are driven by electric motors, combustion turbines, or reciprocating internal combustion engines.

Q2: If the compressor is rated at 1000 hp and the engine is 500 hp and they replace the engine with a 600 hp without changing the compressor, does that trigger a modification as defined by §60.5365a(j)?

A2: No. The replacement of an engine with one of greater HP would not trigger modification of the compressor station for the purposes of §60.5365a(j), if the design capacity of the compressor to which it powers, was not increased.

When one or more compressors is added or replaced such that the total horsepower of the compressors at an existing compressor station is increased, modification of the compressor station is triggered, and the fugitive emissions requirements in §60.5397a of subpart OOOOa would then apply. Some additional information which may be helpful may be found at 81 FR 35864:

The EPA agrees that an increase in the

compression capacity that is not due to

the addition of a compressor that would

result in an increase of the overall

design capacity of the compressor

station is not a modification. For

example, a compressor station may have to increase the operating throughput by bringing existing compressors on-line to meet demand during peak seasons. In such a case, the compressors' capacities are already accounted for in the overall design capacity for the compressor station, and bringing them on-line would not increase the overall design capacity nor would it increase the potential emissions of the compressor station.